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Review of transmission schemes and case studies for renewable power integration into the remote grid

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ABSTRACT

Investment in transmission for *renewable power penetration* to the remote grid essentially faces a set of inherent, regulatory, economic and technical challenges. This work investigates these challenges to enhance renewable power integration into the remote grid. This study aims to enhance regulatory policies and associated planning frameworks to be more efficient and justifiable for renewable power integration paradigm. First, a set of leading transmission schemes practiced, or investigated, in different countries are evaluated against the challenges which are obvious for long distance renewable power transmission. Second, a *net benefit framework* is presented to address the challenging issues of *location constrained renewable power penetration* into the Queensland network of the Australian grid. The proposed framework incorporates the carbon emission price as an *environmental benefit* which significantly influences the cost–benefit analysis. This paper discusses the '*hub approach*' of network integration. The *transmission investment cost allocation* is addressed here as well. The concepts are verified through the implementation of the proposed framework in four prospective projects of the *Queensland network* in the Australian national electricity market (NEM).

Contents

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1. Introduction

Due to the combined effects of restructuring, environmental concerns and emission trading schemes, the electricity market worldwide is experiencing a shifting trend in generation portfolio and real time dispatch [1,2]. Adequate transmission infrastructure and a suitable investment scheme to meet the evolving market structure has emerged as a critical need to meet the new generation investment and dispatch pattern. Consequently, the generation shift and transmission investment bring many technical and economic challenges for planning and operation of electricity markets that need to be addressed through development of new analytical approaches, e.g., [3].

Looking at some of the market specific experiences, challenges of renewable transmission investment and regulatory amendments for the UK, Brazil and Chilean grids are reported in [4]. In addition, the problems of the USA grid for large scale renewable power integration are discussed in [5]. Some potential discussion of possible avenues to contemplate efficient planning has also been identified in that study. In another work, Swider et al. [6] presented the transmission cost allocation issues in seven European countries and discussed conditions and barriers to promote renewable power integration to a remote grid. In a detailed study, Great Britain's practice to employ a new transmission pricing method is presented in [7]. That study also considered four scenarios of the GB electricity network, around the 2020 '*FutureNet*' program including the transmission cost sensitivity on generation, demand and network topology. The strategies of the Spanish electricity grid reform is reported in [1], that includes inter alia combinations of load conditions, generation profile and network status. Amendments for planning and building large scale transmission networks in Brazil are discussed in [8] that highlight the technical, economic and regulatory challenges.

The regulatory investment test for transmission (RIT-T) is used in the Australian national electricity market (NEM) as the central mechanism to decide transmission investment that includes an explicit cost–benefit test and assessment of market benefit of transmission. While it has a number of attractive features, it also has some shortcoming when it comes to large scale renewable power integration to the grid from a remote location [9]. Although the scale efficient network extension (SENE) was promulgated by the Australian Energy Market Commission for the Australian NEM to get around the transmission investment issues, the scheme was subsequently dropped citing implementation difficulties [10]. Also a low emission generation enhancing transmission scheme is proposed in the NEM for the Victorian generation clusters' connection (VGCC) [11]. In the UK electricity market, the Office of Gas and Electricity Market (OFGEM) has introduced a scheme to provide incentives to transmission projects based on the available renewable resources, appropriate constraint costs and required investments [12]. In the California ISO, a special arrangement for remote renewable generator connections is reported known as the '*location constrained resource interconnection*' [13]. The California Energy Commission proposes a '*strategic transmission investment plan*' to promote environment driven transmission expansion [14]. Details of these transmission schemes are discussed in a later section. Investigations through all of the relevant studies affirm the need for an efficient regulatory framework, economic model, network structure and market response to mitigate the renewable power integration challenges [15].

In order to address the renewable power integration issues comprehensively, planners need to develop a proper analytical framework to adequately deal with the challenges that large scale renewable resources present. This study aims to develop such a framework in the Australian context and in particular highlights the impact and potential of remote transmission investments on the net market benefit. Four case studies have been presented that focus on proposed long distance renewable power integration into the Queensland electricity network.

The rest of the paper is organized as follows. Section 2 presents the challenges of renewable power penetration to the remote grid, followed by a review of some leading transmission schemes to meet those challenges in Section 3. A net market benefit framework is described in Section 4 followed by Section 5 that deals with case studies of four prospective large scale renewable power projects to be connected to the Australian *Queensland network*. Analytical results and conclusions are presented in Sections 6 and 7, respectively.

2. Challenges of renewable power penetration to remote grid

Renewable power penetration from remote location constrained generators to the grid is facing a set of challenges. Those challenges are categorized here as inherent, regulatory, economic and technical aspects.

Nomenclature

a_i, b_i, c_i	Cost coefficients of generator i
Cap_i	Capacity of generator i (MW)
CS_d^i	Consumer surplus earned by consumer i (\$)
$CS_d^{i\prime}$	Consumer surplus before augmentation (\$)
d	Demand (used as subscript)
E_i	Amount of CO_2 produced by generator i (ton)
F_f	Branch flow at '*for end*' (MW)
F_t	Branch flow at '*to end*' (MW)
$F_{\max}$	Maximum limit of branch flow (MW)
f_p^i	Cost function of generator i
g	Generator (used as subscript)
n_d	Number of load set
n_g	Number of generator set
p_{bus}	Real power of a bus (MW)
Q_{bus}	Reactive power of a bus (MVAR)
p_d	Real power of the load (MW)
Q_d	Reactive power of the load (MVAR)
p_d^i	Power consumed by load i (MW)
p_g^i	Power produced by generator i (MW)
PC_g^i	Producer cost incurred by generator i (\$)
PR_g^i	Producer revenue earned by generator i (\$)
PS_g^i	Producer surplus earned by generator i (\$)
r	Discount rate
t	Time span (hour)
V_m	Voltage magnitude (Volt)
y	Number of years
λ^k	Locational marginal price (LMP) at bus k (\$/MWh)
λ_g^i	LMP at generator bus, for generator i (\$/MWh)
λ_d^i	LMP at load bus for load i (\$/MWh)
ϕ_g^i	Generation cost of generator i (\$/MWh)
ψ_i	Amount of renewable generation from generator i (MW)
π_{co_2}	Emission cost (\$/ton CO_2)
σ	LRET payment (\$/MWh)
θ	Voltage angle

2.1. Inherent challenges

Inherent challenges are the uncertainty in generation and demand, balance between generation and demand and *free rider problem*. Significant generation expansion and demand growth in different parts of the network causes major uncertainty in transmission planning. Uncertainty in the planning horizon can be categorized in two aspects—probabilistic and possibilistic [16]. Probabilistic methods are applicable to stochastic parameters which follow a probability distribution, i.e., wind power follows a Weibull distribution. Alternatively possibilistic approach is preferable to non stochastic parameters, i.e., electrical load, installed capacity and controllable generators do not follow any probability distribution [17]. A system planning model requires these uncertainty considerations to address the practical issues appropriately [18–21]. However, as the prime focus of this paper is regulatory and economic aspects, detailed discussion of uncertainty modelling is reduced to limit the scope of the paper.

Another aspect of the challenge is the "*chicken and egg*" dilemma, i.e., which should come first—generation, or transmission. A generator needs to be assured that there are adequate transmissions facilities. On the other hand, transmission investors need firm generation expansion projects to ensure a certain level of utilisation of the transmission assets [8]. A generator paying for transmission upfront also faces the *first mover disadvantage*. Moreover, once the first generator builds a transmission line to be connected to the network, network sharing and cost allocation becomes contentious when any other generator is to be connected to the existing transmission corridor [6,9].

2.2. Regulatory and economic challenges

Another fundamental challenge of connecting remote *location constrained renewable resources* to the grid is to endure the regulatory investment test and cost–benefit assessment policies. The shortfall of long distance remote transmission is the underlying high investment cost [15]. A high investment disproportionate to the quantified benefits of the long distance transmission may defer, or abandon, the grid integration [22]. In this regard, accumulation of strategic benefits of network augmentation is a critical issue to justify large initial invest

Economic challenges include the *economies of scale* and competition with conventional generation sources. The economic aspects also address the transmission investment cost allocation and transmission cost recovery. Cost allocation issues have received significant attention due to the fact that the transmission cost of connecting remote renewable power is significant compared to connecting conventional power stations [9]. Hence, achieving the *economies of scale* in this prospect is a highly decisive factor [8,15]. Further, remote location constrained renewable resources compete with nearby conventional power plants to pass the economic tests [8].

Some challenges which fall both in the *regulatory* and *economic* regimes are stranding asset risk, capturing strategic benefits, transmission investment cost allocation and (deep, shallow or hybrid) cost burden on generators [6,9]. Regulatory policies do not facilitate the recovery of costs of over built transmission infrastructures [2], particularly if the transmission infrastructure is developed and no/little generation eventuates then the investment is at risk of being stranded. Traditional regulatory frameworks fail to capture some unquantifiable benefits which are obtained through renewable generation entry to the electricity market [4]. Although the societal benefit of scale efficient transmission is well understood, the issue of cost allocation poses a significant hurdle [9]. Moreover, the remuneration of renewable transmission investment through the *transmission use of system charges* is still an emergent issue [8].

2.3. Technical challenges

Technical challenges address the connection topology (spaghetti network or hub connection) and connection technology (HVAC, HVDC). Every generator of a *remote generation cluster* can be connected to the grid on its own which creates the so called *spaghetti network* as shown in Fig. 1a. For *location constrained remote generation resources* this type of connection is not efficient and economic [9,15]. Rather, a high voltage transmission line can connect the remote generation zone to load centres, where successive generators can be connected to the high capacity line as shown in Fig. 1b. This is known as the scale efficient network extension (SENE) framework [23]. Another option could be to establish a hub in the SENE approach as shown in Fig. 1c. The location of the hub would be decided based on the market operator's policy. Regarding the transmission technology, if there are a few thousands of MW of generation at a specific location, then an extra high-voltage (i.e., 800 kV) HVDC line could be justifiable [8]. However, the possibility of staged development or tapping in between the transmission corridor can play an

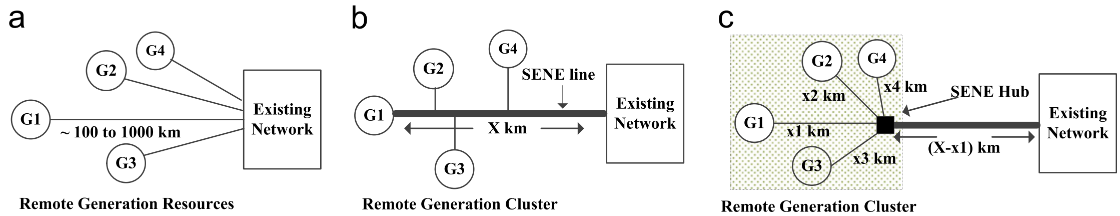

Fig. 1. Transmission topologies for remote generation connection.

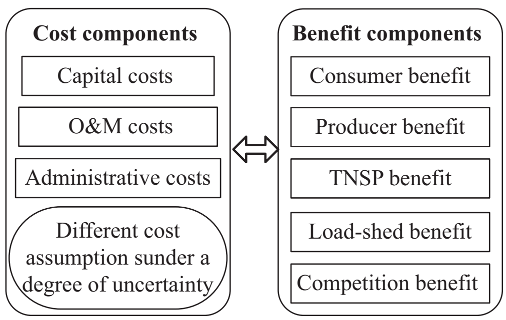

Fig. 2. Regulatory Investment Test for Transmission (RIT-T) of the Australian NEM [18].

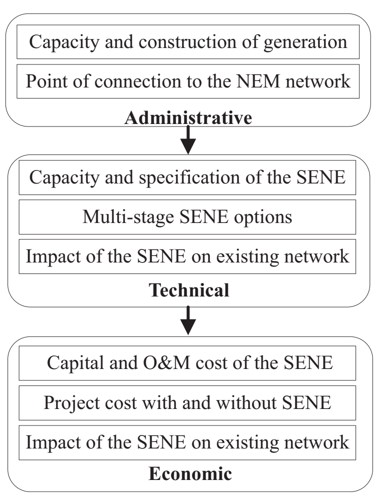

Fig. 3. Scale efficient network extension (SENE) proposal of the Australian NEM. [17].

important role in determining the technology (HVDC or HVAC), voltage level and network configuration (i.e., spaghetti, or SENE, or hub).

3. Review of transmission schemes to meet the challenges of renewable power integration into the remote grid

An overview of some leading global transmission planning frameworks has been presented here. These frameworks are analysed against the aforementioned challenges of remote renewable power penetration into the existing grid. The review accordingly demonstrates the need for changes to the traditional approaches to meet the present challenges.

3.1. Regulatory investment test for transmission (RIT-T) [24]

The RIT-T is a cost–benefit assessment framework for transmission network augmentations in the Australian NEM. This framework puts forward the credible option which offers maximum net benefit for all of the market participants, where

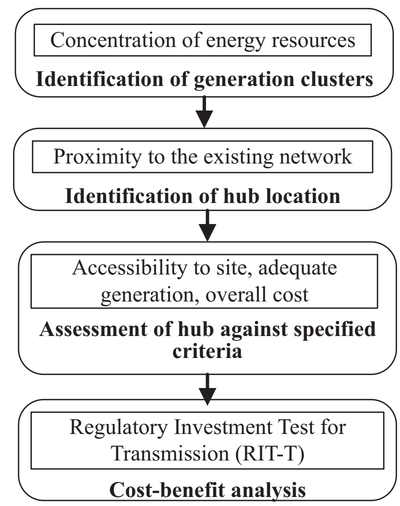

Fig. 4. VGCC proposal of the Victorian network [11].

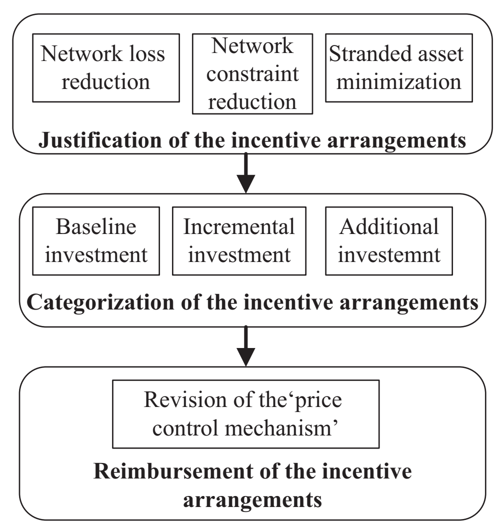

Fig. 5. Transmission investment incentives scheme of OFGEM [12].

"*net economic benefit equals the market benefit less costs*". Fig. 2 shows the block diagram of the steps of RIT-T evaluation. Costs of transmission augmentation mainly consist of capital investment, operation and maintenance costs. A degree of uncertainty in the cost is considered under different ranges of cost assumptions. Market benefits occur to both suppliers and consumers as measured via producer and consumer surplus, respectively. Competition benefit which reflects the reduction of exercising market power is also an important component as discussed in [24]. *Economies of scale* and *stranding asset risk* are however not addressed in the RIT-T framework. The free rider problem will not arise as there is no scope for a pro-active approach. A spaghetti network may emerge in this framework because the RIT-T is applied to each network augmentation in isolation,

without giving any holistic consideration to scale efficiency. There is no deep, shallow or super shallow option for generators. An important upshot of the RIT-T framework is that renewable generation in remote locations do not secure any advantage from scale efficiency of generation or transmission and therefore competition with gas-based generation will delay or defer the renewable integration.

3.2. *Scale efficient network extension (SENE) [9,23]*

The SENE was proposed for the Australian NEM to integrate large scale location constrained generation resources into the grid [10]. The SENE would confirm sufficient transmission facilities for accommodating future generation to obtain the *scale of economies*, though a *risk of asset standing* is involved here [9,25]. Fig. 3 presents the conceptual framework of the SENE. Traditionally the National Electricity Rule imposes the responsibility on the connecting generators to promote and fund the network extension. On the other hand, the proposed SENE scheme recommends the network service providers to plan and develop the extensions to the SENE zones identified by the Australian Energy Market Operator's (AEMO) national transmission network development plan. Later, the generators will pay the connection fee while they connect to the extensions. The customers will pay the shortfall if anticipated funding is not forthcoming from the generators [25]. This method was developed to achieve the *economies of scale*. This approach lessens the chicken and egg dilemma and first mover disadvantages, but the success mainly depends on handling the risk of stranding assets [9].

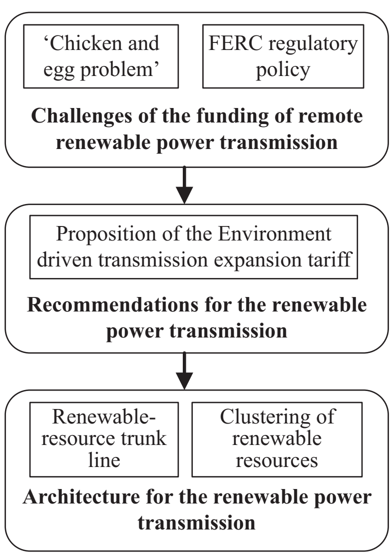

Fig. 6. Renewable intensive transmission investment of CA Energy Commission [14].

3.3. *Victorian generation clusters' connection (VGCC) [11]*

The VGCC scheme will be used in addition to the RIT-T framework. This approach is developed for connecting Victorian generators to the Australian NEM grid. In response to the Australian government's carbon policy many low emission generators are applying to connect to the existing high voltage transmission lines. For connecting new generators the current practice is either to connect through a dedicated terminal, or through an existing terminal station. The VGCC approach proposes to connect the generation clusters to a connection hub which will then to be connected to the existing grid. The selection criteria and stages of assessment of VGCC are shown in Fig. 4. Assessment of the hub location is based on some specific criteria such as the concentration of energy resources, proximity to a transmission corridor, accessibility for building infrastructure, overall cost and environmental impacts [11]. This option proposes a hub network structure to connect many generators to the high voltage transmission line, which will eventually reduce network interruptions.

3.4. *Transmission investment incentives (by OFGEM) [12]*

The Office of Gas and Electricity Markets (OFGEM) of UK has "set out the incentive arrangements and adjustment mechanism for the funding of transmission investment for renewable generation" [12]. Investment required to reinforce the transmission system must be justified by reducing the cost of network and transmission losses. Fig. 5 shows the conceptual framework of the transmission incentive scheme proposed by the OFGEM. Based on the available renewable resources, appropriate constraint costs and required investments, incentives will be allocated to three categories of projects—(1) baseline investment—which is clearly justified through the cost–benefit analysis (CBA). For these projects savings from constraint costs would be greater than investment costs. (2) Incremental investment—there are some uncertainties to pass the CBA. Under this category, constraint costs are significant but there is uncertainty if they are greater than the investment. (3) Additional investment—significant uncertainty and high risk of stranding assets. For these projects,

Table 1
Overview of transmission methodologies to meet challenges of renewable power penetration to remote grid.

		RIT-T	SENE	VGCC	OFGEM	CEC	LCRI
Inherent	Generation-load uncertainty	✓	✓	✓	✓	✓	✓
	Generation-load balance	✓	✓	✓	✓	✓	✓
	Chicken and egg dilemma	×	✓	×	✓	✓	✓
	First mover disadvantages	×	✓	×	×	✓	✓
	Free rider problem	×	✓	×	×	×	✓
Regulatory	Cost–benefit analysis	✓	✓	✓	✓	✓	✓
Economic	Economies of scale	×	✓	×	✓	✓	✓
	Competition with grid-nearby gas generation	✓	✓	✓	✓	✓	✓
Regulatory and economic	Strategic benefits	×	✓	×	×	✓	✓
	Environmental benefit	×	✓	×	✓	×	✓
	Stranding asset risk	×	✓	×	✓	✓	×
	Transmission investment and cost allocation	✓	×	✓	✓	✓	✓
	Deep, shallow, super-shallow	×	✓	✓	×	×	✓
Technical	Transmission topology	×	✓	✓	×	✓	×
	Transmission technology	×	✓	✓	×	✓	×

constraint cost is less than half of the investment and there is a significant risk of stranding assets [12]. Free rider problem, economies of scale and stranding asset risks have been resolved through incentives and funding arrangements. However, there is no clear direction about the transmission topology and technology.

3.5. Strategic transmission investment plan (by CEC) [14]

In the strategic transmission investment plan by the California Energy Commission (CEC), two probable avenues are offered to resolve the long distance renewable power transmission problems: One is providing a special type of transmission facility, namely, '*renewable-resource trunk line*' to connect large potential renewable generators to the existing grid. The cost of developing the line would be covered through general transmission rates. The other is the '*clustering*' of renewable generation projects to build transmission lines from potential generation zones. The block diagram of the strategic transmission investment plan is shown in Fig. 6. As the current California Independent System Operator (CAISO) and Federal Energy Regulatory Commission (FERC) policies do not support this approach—necessary regulatory changes are recommended. In addition to currently recognized *economically driven* and *reliability driven* projects, regulatory changes to support a third type of project namely *environment driven* transmission expansion tariff is proposed [14].

Table 1 presents a comparative overview of the existing transmission methodologies to meet the challenges of renewable power penetration to the remote grid.

3.6. Location constrained resource interconnection (LCRI) [13]

The LCRI generators located in a remote area will get the facility to be connected to the network under this scheme. Fig. 7 presents the block diagram of the LCRI scheme of the CAISO. This scheme offers a high voltage transmission facility which should comply with ISO grid planning standards and reliability requirements. As a guarantee for building such a network, at least 25% of the capacity of the transmission facility has to be committed. Evaluation of the LCRI facility (LCRIF) has to justify the trade-off between estimated costs/projected benefits, potential capacity of the LCRIGs, schedule of the transmission facility, additional

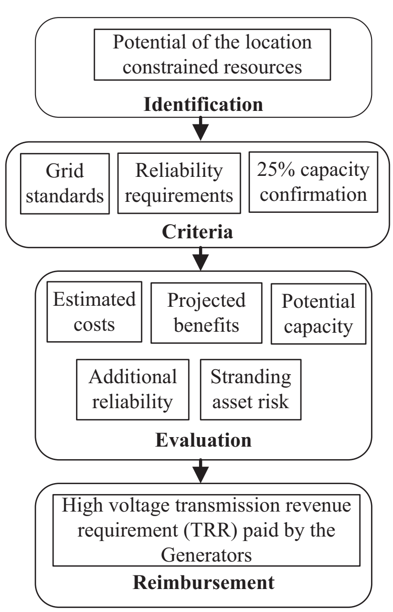

Fig. 7. Location constrained resource interconnection (LCRI) scheme of the CAISO. [13].

reliability and economic benefits. Participating generators of the LCRIF pay a high voltage transmission revenue requirement (TRR) to the transmission operator according to their maximum capacity relative to the capacity of the LCRIF. Accordingly, every LCRIG will pay its '*pro rata*' share of the high voltage TRR [13]. Still, there are some missing components of efficient transmission scheme like *stranding asset risk*, *transmission topology* and *transmission technology*.

4. Net market benefit evaluation approach

4.1. Evaluation of market benefit

Market benefit evaluation frameworks have been widely used in the electricity industry to assess transmission projects based on the cost–benefit aspects. Considering the total market benefit evaluation process, producer and consumer benefits have been assessed. In this research the net market benefit evaluation framework has been updated with environmental surplus. Transmission projects that enhance remote renewable generation should explicitly include environmental benefits in their project assessment. The environmental benefit is assessed based on emission pricing and the large scale renewable energy target (LRET) scheme of the Australian NEM. The objective function consists of the producer surplus, consumer surplus, merchandizing surplus, emission tax and LRET surplus. The objective function of the net market benefit is formulated as below:

$$\mathrm{Max}\sum_{t=0}^{8760}\left[\sum_{i\in n_g}\left(p_g^i\times\lambda_g^i-p_g^i\times\phi_g^i\right)+\sum_{i\in n_d}\left(CS_d^{i\prime}-CS_d^i\right)+\left(\sum_{i\in n_d}p_d^i\times\lambda_d^i-\sum_{i\in n_g}p_g^i\times\lambda_g^i\right)-\left(\sum_{i\in n_g}E_i\times\pi_{CO_2}\right)+\left(\sum\psi_i\times\sigma\right)\right] \quad (1)$$

4.1.1. OPF formulation

The AC optimal power flow (OPF) solution is executed through the MATLAB Interior Point Solver (MIPS) algorithm which is implemented in the MATPOWER 4 version. Generation cost information is obtained from the Australian NEM [26,27]. The objective function of the OPF considers the polynomial cost function of real power injections for each generator as follows [28]:

$$\min\sum_{i\in n_g}f_P^i\left(p_g^i\right)=\min\sum_{i\in n_g}\left(a_ip_g^i2+b_ip_g^i+c_i\right) \quad (2)$$

In the OPF algorithm, the power balance equality constraints are

$$g_P\left(\theta,V,P_g\right)=P_{\mathrm{bus}}(\theta,V)+P_d-P_g=0 \quad (3)$$

$$g_Q\left(\theta,V,Q_g\right)=Q_{\mathrm{bus}}(\theta,V)+Q_d-Q_g=0 \quad (4)$$

Branch flow limit inequality constraints are

$$h_f(\theta,V)=\left|F_f(\theta,V)\right|-F_{\max}\le 0 \quad (5)$$

$$h_t(\theta,V)=\left|F_t(\theta,V)\right|-F_{\max}\le 0 \quad (6)$$

Variable limits are

$$\theta^i_{\min,\ \mathrm{ref}}\le\theta_i\le\theta^i_{\max,\ \mathrm{ref}} \quad (7)$$

$$V^i_{m,\ \min}\le V^i_m\le V^i_{m,\ \max} \quad (8)$$

$$P^i_{g,\ \min}\le P^i_g\le P^i_{g,\ \max} \quad (9)$$

Different components of the net benefit framework have been described and formulated below [15,29,30].

4.1.2. Producer surplus

The producer surplus arises from the total generation revenue by generators less the generation cost, which can be expressed as below:

$$\sum_{t=0}^{8760}\sum_{i\in n_g}\left(PR_g^i - PC_g^i\right) = \sum_{t=0}^{8760}\sum_{i\in n_g}\left(p_g^i \times \lambda_g^i - p_g^i \times \phi_g^i\right) \tag{10}$$

4.1.3. Consumer surplus

The consumer surplus considers the incremental benefit of consumers due to the augmentation. Fig. 8 shows the market bidding behaviour with a supply and demand curve, which provides producer and consumer surplus. The price elasticity of demand is considered in this study as −0.3, which is the long run elasticity estimation for the Queensland electricity market [31].

$$\sum_{t=0}^{8760}\sum_{j\in n_d}\left(CS_d^{i\prime} - CS_d^i\right) \tag{11}$$

4.1.4. Merchandizing surplus

Merchandizing surplus is the difference between the total consumer payments less the generation income, as presented below:

$$\sum_{t=0}^{8760}\left(\sum_{j\in n_d} p_d^j \times \lambda_d^j - \sum_{i\in n_g} p_g^i \times \lambda_g^i\right) \tag{12}$$

4.1.5. Emission tax

The carbon price scheme has been considered as presented in Table A2. Emission tax is evaluated in monetary terms as follows:

$$\sum_{t=0}^{8760}\left(\sum_{i\in n_g} E_i \times \pi_{CO_2}\right) \tag{13}$$

4.1.6. LRET benefit

The LRET model used in this study is adopted from the Australian NEM [32]. The numbers of large scale generation certificate LGCs to be purchased are calculated using the renewable power percentage (RPP). RPP is determined using the following formula [32]:

$$\text{RPP} = \text{RPP for the previous year} \times \frac{\text{Required GW h of renewable source electricity for the year}}{\text{Required GW h of renewable source electricity for the previous year}} \tag{14}$$

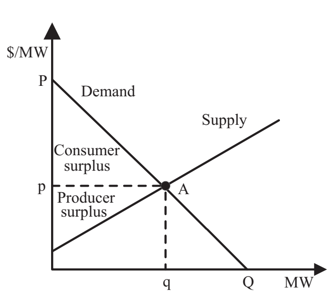

Fig. 8. Consumer and producer surplus.

4.2. Cost considerations

The capital costs of generation and transmission are annualized. The lifespan for generation and transmission projects are considered as 25 and 40 years, respectively [33,34]. The discount rate is assumed to be 10%. The annual required revenue (ARR) is calculated using the following formula [33]:

$$\text{ARR} = \frac{r(1+r)^y}{(1+r)^y - 1} \tag{15}$$

This formula gives an ARR of 0.11 and 0.10 for generation and transmission projects, correspondingly. So, the annualized cost is 11% and 10% of the total capital investment for generation and transmission, respectively.

4.3. Payback scheme and cost recovery mechanism

There are two schemes which have been proposed for transmission cost recovery [10]. Fig. 9a and b demonstrate the transmission investment recovery mechanisms which are implemented in this research. In one scheme (as shown in Fig. 9a), customers pay permanently for the stranded assets. In another scheme (as shown in Fig. 9b), the customers get back a rebate from the consecutive generation payment.

The initial investment can be obtained for every MWh as presented below:

$$\frac{\text{ARR}}{\sum_i Cap_i} \tag{16}$$

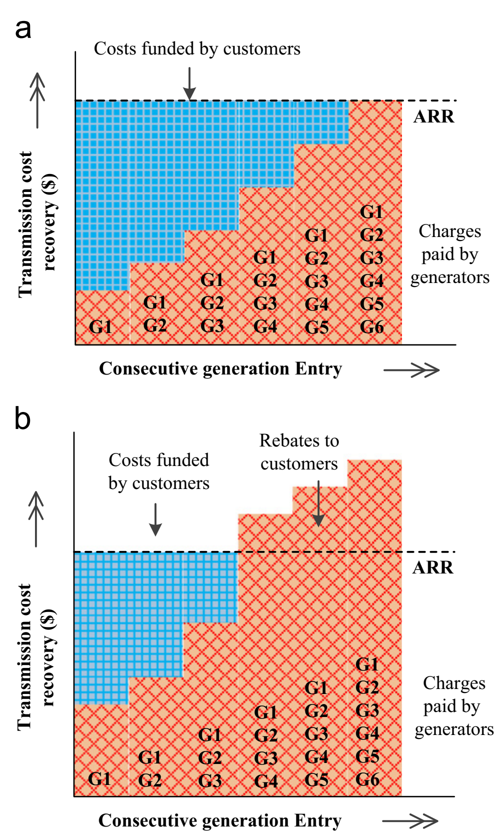

Fig. 9. (a) Transmission investment rebate—customers pay permanently for standing asset. (b) Transmission investment rebate—customers get back rebate.

The tariff charge paid by a specific generator is,

$$\mathrm{ARR} \times \frac{\mathrm{Max}Cap_i}{\sum_i Cap_i} \tag{17}$$

Whenever the annual revenue requirement is totally rebated from the generator payments the transmission facilities become network facilities. Then the general charging and rules will be applicable to that facility.

5. Case studies

5.1. Queensland network

Concepts are verified through the Queensland network which is located in the North-Eastern part of the Australian national electricity market (NEM). It is a 1700 km network along the coastal area having a generation capacity of 12,788 MW and a summer peak demand of 8489 MW in 2010. The relevant data of the Queensland electricity market has been obtained from the publicly available Powerlink Annual Report, 2011, and AEMO's 2011 Electricity Statement of Opportunities for the National Electricity Market [31,35]. Other realistic assumptions and future market conjectures are obtained from the ACIL Tasman report, 'Fuel resource, new entry and generation costs in the NEM' [36].

Considering the national transmission flow path the Queensland network is divided into four zones which are—North Queensland (NQ), Central Queensland (CQ), South West Queensland (SWQ) and South East Queensland (SEQ) [35]. Loads are generally located in the SEQ (63%) region, whereas generations are mostly in the CQ (48%) and SWQ (40%) regions. Promising renewable generation sites are located far away from the load centre. Therefore a variety of key factors (fuel availability, network congestion, network losses and pricing) affect the investment decisions to send power to the load centre at SEQ.

Fig. 10 shows the map of Queensland with existing and prospective power plants. Relevant network and market data is presented in the Appendix. Table 2 shows the potential new generation sites of the Queensland area [36]. Prospective gas generation locations are comparatively closer to the grid. Whereas, coal and wind generation sites are far away from the grid. The geothermal generation zone is very remote and approximately 1000 km away from the existing Queensland grid.

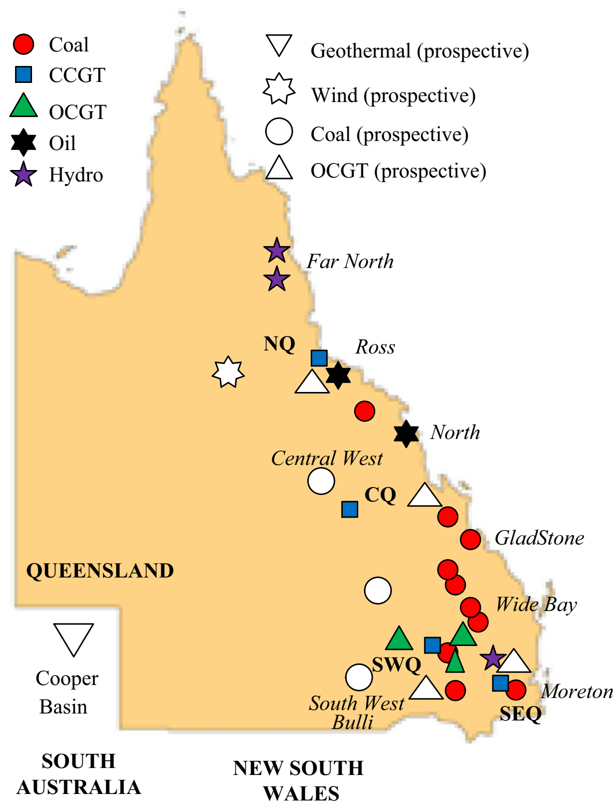

Fig. 10. Queensland network of the Australian NEM [29,31].

5.2. Case studies overview

Four candidate projects of the Queensland network are evaluated to assess their net market benefits. These projects considered large scale renewable power penetration to the existing Queensland grid. Table 3 presents the location, generation resource, distance and approximate investment in these projects. A brief overview of the projects is given below.

5.2.1. Kennedy Wind Farm (700 MW, 290 km) [37]

The Kennedy Wind Farm Project connects Hughenden, located approximately 290 km South-West of Townsville to the existing Queensland grid. Hughenden is a renewable energy hub resourced with wind, solar, geothermal and biomass. The 290 km transmission line is designed for a capacity of 700 MW. Approval was sought for this project in late 2011, construction is scheduled from 2012 and commercial operation in expected from 2014.

Table 2
Prospective location of new power plants in Queensland.

NEM zone	Gas	Coal	Wind	Geothermal
NQ	Townsville	Northern Bowen Basin	Flinders Shire	Cooper Basin, Border of South Australia and Queensland
CQ	Gladstone	Southern Galilee Basin	–	
SEQ	Swanbank	–	–	
SWQ	Braemer	Surat Basin	–	

Table 3
Four large-scale prospective renewable projects to be connected to the Queensland network.

Project	Location	Source	Generation (MW)	Investment (m$)	Distance (km)
Kennedy Wind Farm	NQ	Wind	700	1920	290
Copper String project	NQ	Wind	400	1680	720
Cooper Basin Geothermal	SWQ	Geothermal	2000	12000	1000
PNG Hydro	NQ	Hydro	1800	6470	250 cable+200

5.2.2. Copper String Project (400 MW, 720 km) [38]

The Copper String transmission project connects the Mount Isa region of North West Queensland to Townsville. It is designed for a capacity of 400 MW with a length of 720 km. This project will provide opportunities for renewable energy projects surrounding the proposed transmission line. An environmental impact statement (EIS) process is under review for this project. Construction is scheduled to start in late 2012 and the project completion date is early 2015.

5.2.3. Cooper Basin Geothermal (2000 MW, 1000 km) [39]

The Cooper Basin transmission line connects hot fractured rock based geothermal power generators located 1000 km away from the existing Queensland grid. It is reported that there is a potential of 4000 MW of geothermal power to be connected to the grid by 2030 [39]. In this case study, transmission connection is designed for a capacity of 2000 MW. As reported by the Geodynamics, construction and commissioning of a 25 MW commercial demonstration plant is scheduled for 2015 [40].

5.2.4. PNG Hydro (1800 MW, 250 km cable+200 km)

A new transmission line will connect Papua New Guinea (PNG) to the existing NEM grid to provide 1800 MW of hydro power. A 250 km subsea cable along with 200 km overhead transmission line is designed to transfer baseload hydro power.

As the Queensland network is connected to the other states (i.e., NSW, VIC, SA and TAS) of the NEM, the benefit of the generation and transmission expands to the whole NEM network. However, this study only investigates the benefits obtained by the Queensland network.

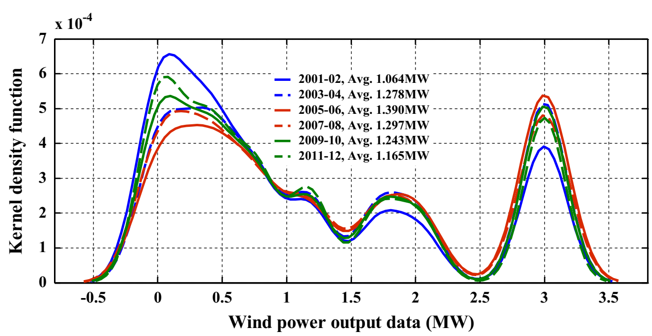

Fig. 11. Kernel smoothing density estimate of a 3 MW vestas wind turbine output located in Hughenden (Kennedy wind farm).

5.3. Wind power sensitivity

Historical wind data of last 12 years (2001 to 2012) for Copper String (Hughenden) and Kennedy Wind Farm (Mt. Isa) have been obtained from the Australian bureau of meteorology [41]. Those wind data are modelled in MATLAB using the Vestas V112 3 MW wind turbine features (Rated power: 3075 kW, Cut-in wind speed: 3 ms^{-1}, Rated wind speed: 12 ms^{-1}, Cut-out wind speed: 25 ms^{-1}, Swept area: 9,852 m^2, Frequency: 50/60 Hz) [42]. This type of Vestas turbine is suitable for low and medium wind speed sites, as experienced in Queensland. The power obtained from the simulation is shown as kernel smoothing density estimation as in Fig. 11.

The power obtained from a wind turbine is zero below and near cut in speed. As the wind speed increases the power increases. At 12 ms^{-1} the power reaches to 3 MW, and until 25 ms^{-1} it gives an output of the same level. Above that speed the wind turbine shuts down. Hence, according to the wind turbine characteristics the wind generation have a peak at lower power in kernel density function, and another peak in the rated capacity of 3 MW, as shown in Fig. 11.

Capacity factor for the Australian wind farms is usually in the range of 24–45% [43]. This study considers 35% capacity factor of these wind farms for all of the calculations. Further, the wind power sensitivity impact on the system performance is discussed in Section 6.8.

6. Analytical results

The impact and potential of future market scenarios are analysed and ranked based on the net market benefit. Simulation results are interpreted based on the monetary metrics calculated for a range of market development scenarios. The optimum timing of integrating several projects to the Queensland network is analysed from simulation results of 2010 to 2020. First, an hourly OPF calculates the power flows and market dispatch. Then by aggregating the producer surplus, consumer surplus, merchandizing surplus, emission tax and LRET benefit underlying these flows/dispatch—the net market benefit has been obtained. One important point to note is that the net market benefit presented for every case is calculated by comparing with the base case scenario.

6.1. Producer surplus

Producer surplus, by using Eq. (10) as obtained from the four projects (Copper String, Cooper Basin, Kennedy Wind and PNG

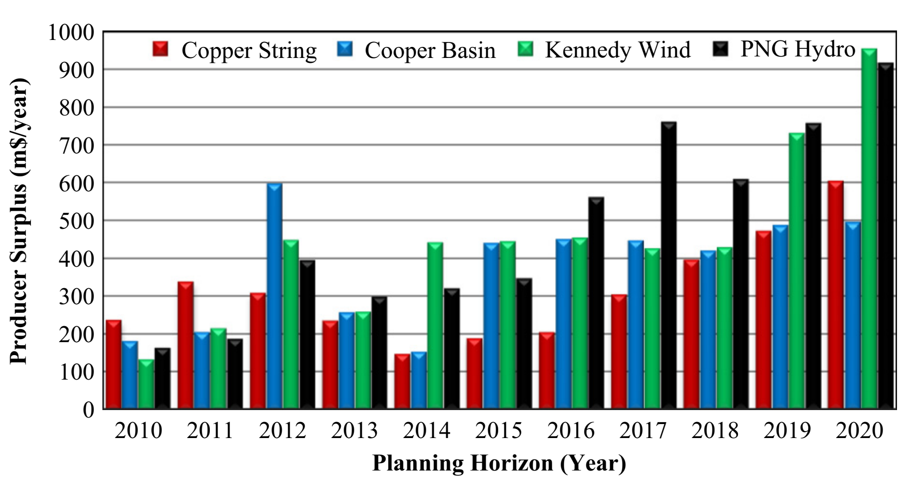

Fig. 12. Producer surplus of the Queensland network for the years 2010–2020.

hydro) has been shown in Fig. 12. There are a number of generation and transmission project interactions that have a bearing on producer surplus. In particular, there are two fundamental factors which have a high influence on the producer benefit. These are the generation load balance and the eventuation of new generation. Producer benefits have been increasing for all five cases according to the increase in generation and demand. Suddenly producer benefits drop in 2013 due to the fact that a 500 MW OCGT (Table A5) is commissioned in that year in the Bulli area (Fig. 10). Another important point to note is that the power penetration to the network from the Cooper Basin project largely affects the producer surplus in 2013 and thereafter. The reason behind this drop in producer surplus is the employment of two 500 MW OCGT in 2013 and 2014 in Bulli, which are injecting power near the load centre of South-East Queensland (SEQ) (also the adjacent area of the geothermal connection point).

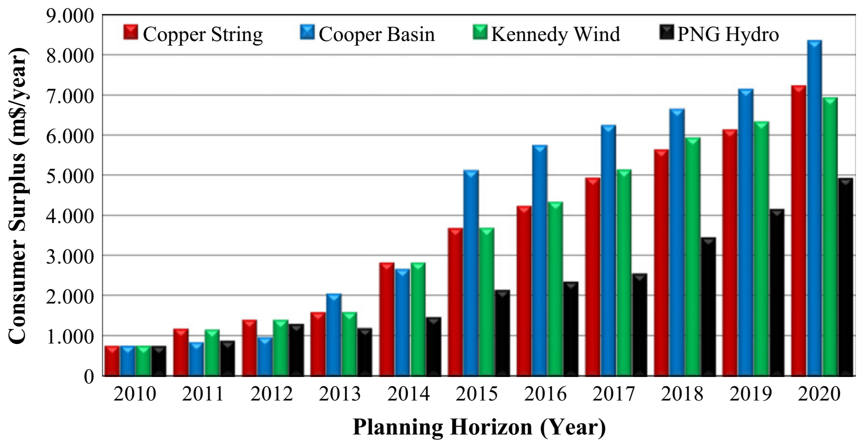

Fig. 13. Consumer surplus of the Queensland network for the years 2010–2020.

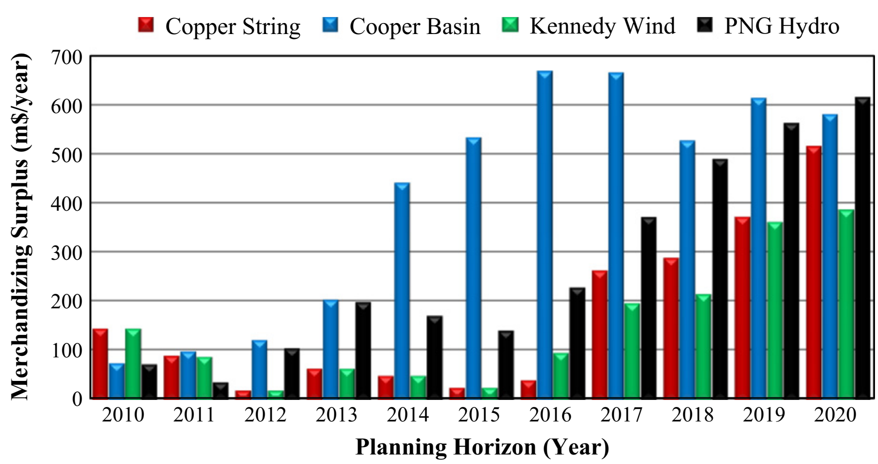

Fig. 14. Merchandizing surplus of the Queensland network for the years 2010–2020.

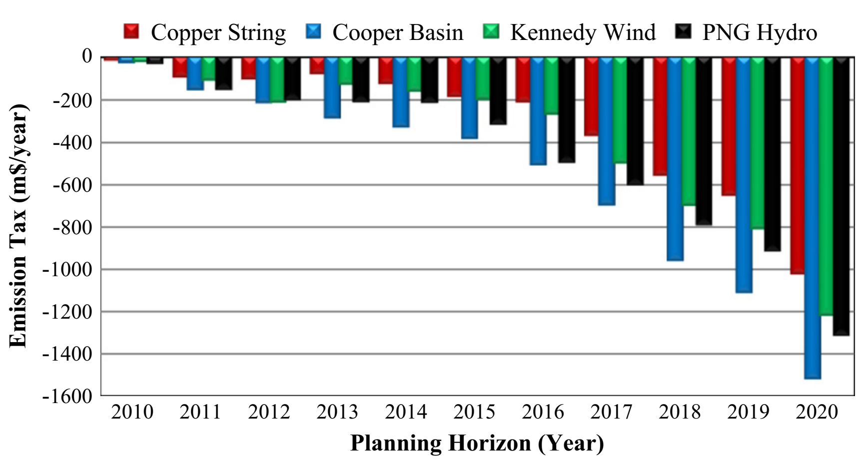

Fig. 15. Emission surplus of the Queensland network for the years 2010–2020.

6.2. Consumer surplus

Fig. 13 shows the consumer surplus as in Eq. (11), for the four projects considered in this study. As for producer surplus, consumer surplus is affected by the network constraints and generation adequacy. Consumer surpluses are increasing consecutively every year as more consumers are being served with additional generation. The impact of the Cooper basin project is significant on the consumer benefit as it is evident from Fig. 13. The reason behind this is the proximity of the point of power injection (Bulli), which is close to the load centre (SEQ) compared to other projects. Low cost geothermal power penetration near the load centre potentially lessens the LMP, which eventually provides a higher consumer benefit.

6.3. Merchandizing surplus

Merchandizing surplus, as described in Eq. (12), is calculated from the Copper String, Cooper Basin, Kennedy Wind and PNG hydro projects and have been shown in Fig. 14. As the merchandizing surplus represents the difference between the consumer payment and the producer income it drops off as consumer payment lessens and vice versa. The yearly incremental merchandizing surplus for all of the projects is reasonable due to the load growth and consecutive LMP increment.

6.4. Carbon emission tax

Carbon emission tax imposed on the pollutant power stations are calculated, by Eq. (13) and presented in Fig. 15. This analysis however, depends on the carbon price imposed on the emission. The emission payments for specific generators are calculated based on the total dispatch, capacity factor, emission factor and the proposed fixed emission price for the NEM [36,44]. As the demand is increasing every year the emission taxes paid by the generators are increasing from 2010 to 2020 for all of the generators. But comparing with the base case, the carbon emission tax is negative, which means that these renewable power generation projects can save the emission tax. It is evident from Fig. 15 that the renewable power penetration to the grid lessens the amount of emission and consequently the emission tax. Also the emission tax depends on the amount of power penetration and the network constraints to inject renewable power near the load centres. As the point of power penetration of the Cooper Basin project is (Bulli) near the load centre (SEQ) compared to the other three projects the renewable power dispatch is higher and the emission tax is lower compared with the base case.

6.5. LRET payment

The LRET payments for the specified case studies are presented in Table 4 and in Fig. 16. The required LRET amount is calculated using the NEM wide target of the renewable power percentage (as discussed in Section 4.1.6) [31,35]. A shortfall of LRET amount imposes a LRET penalty which is A$65/MWh. The LRET incomes for all of the projects are reported in Fig. 16. As can be seen, the LRET payment is increasing in consecutive years due to the dispatch of more renewable power to the electricity market. LRET benefit is calculated as the difference in LRET payment for each of the four scenarios and that in the base case.

6.6. Net market benefit

Net market benefit and annual revenue requirement (ARR) on capital for the Copper String, Cooper Basin, Kennedy Wind and PNG hydro projects are shown in Fig. 17. The ARR is calculated according to the discussion of Section 5.2. The main contribution of the net market benefit comes from the consumer benefit, emission tax and LRET payment. The market benefit of Copper String, Cooper Basin, Kennedy Wind Farm and PNG hydro project overcomes the annual required return on capital from the year 2016 and thereafter. Overall the Cooper Basin project offers the maximum net market benefit, followed by the Kennedy Wind

Table 4
LRET benefit of the Queensland network for the years 2010–2020.

Annual LRET	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base case										
Required (GW h) [37]	2704	4247	4740	4186	4680	5350	6546	7740	8938	10660
Ren. Gen. (GW h)	2890	3041	3179	3560	3806	4267	4455	4894	5038	5989
Payment (m$)	187	197	206	231	247	277	289	318	327	389
Penalty (m$) [37]	12	78	101	40	56	70	135	184	253	303

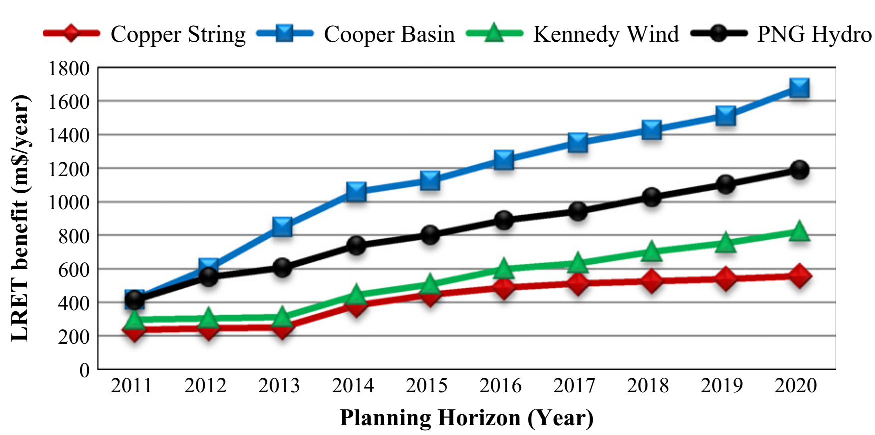

Fig. 16. LRET benefit of the Queensland network for the years 2010–2020.

Farm project. Every project in this study is analysed independently against the base case. Interaction among these projects may also give supportive directions for decision making which will be addressed in our further research.

6.7. Payback scheme

Three cost recovery mechanisms are considered and the results are presented in Fig. 18. The 'total' scheme (bar charts)

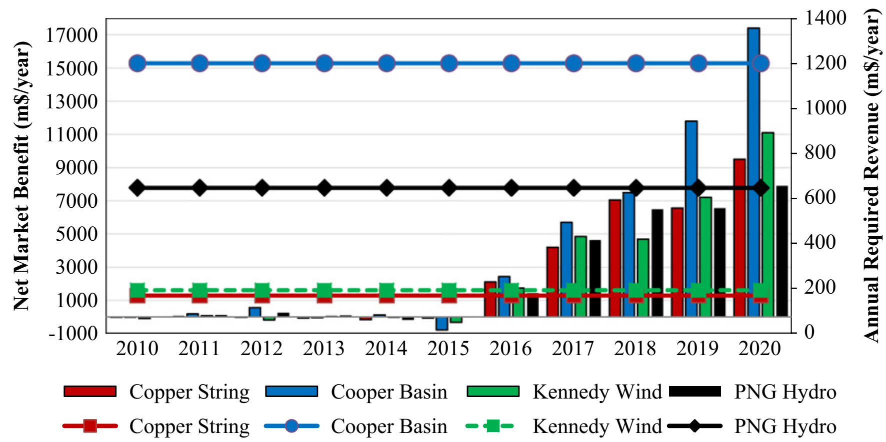

Fig. 17. Net market benefit and ARR of the Queensland network for the years 2010–2020.

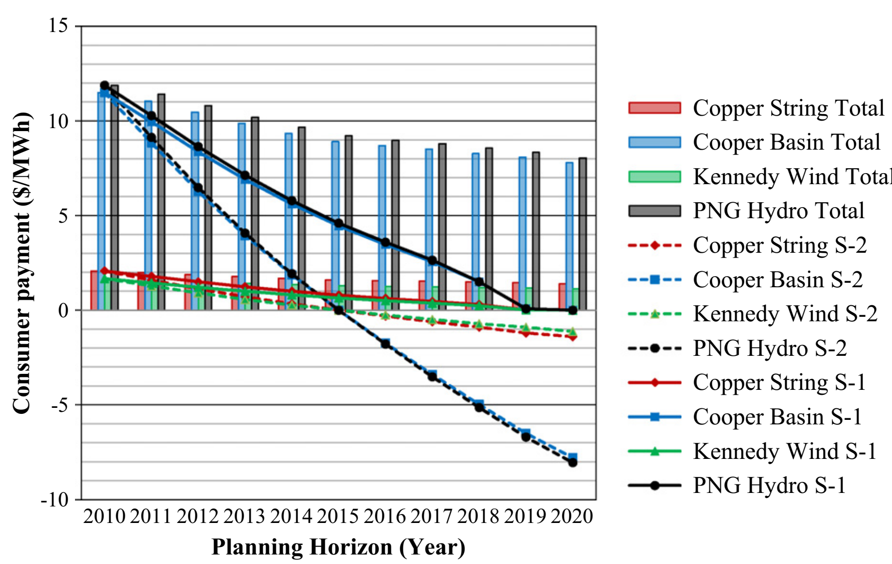

Fig. 18. Payback scheme of the Queensland network for the years 2010–2020.

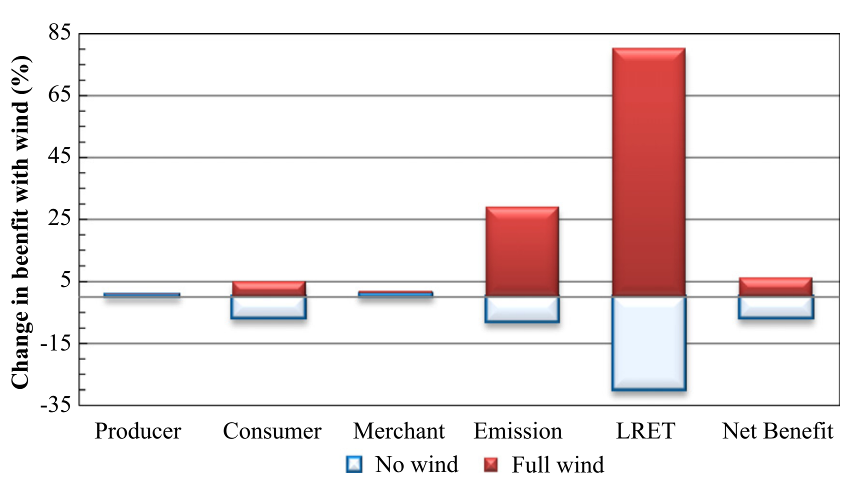

Fig. 19. Changes in market benefit with lower and upper bound the wind generation in Copper string and Kennedy wind farm projects.

presents the result of the scenario when all cost burdens of the transmission development are borne by the customers. The ARR on capital is divided by the total generated energy, as presented in Eqs. (16) and (17). Schemes S-1 and S-2 divide the total transmission cost among all of the consumers by MWh consumption as described in Section 5.3. Scheme S-1 (solid line) gets the cost recovery from the generators as discussed earlier and presented in Fig. 9a. Under this scheme, customer payment reduces to zero with the eventuation of more generators to share the transmission capacity. Scheme S-2 (dashed line) gets back money from the generators and pays back a rebate to the customers as discussed earlier and presented in Fig. 9b. Under this scheme, consumers get back money, which is shown by negative payments.

6.8. Wind power sensitivity

While considering the wind power sensitivity in market analysis, lower bound (no wind) and upper bound (full wind) of the wind power is considered. The impact of these wind power on net market benefit has been analysed. Consequently, the changes in surpluses of producers, consumers, and merchandisers are calculated along with the differences in LRET payments and emission pricing.

The impact of wind power intermittency in market simulation has been shown in Fig. 19. As can be seen from Fig. 19, in no-wind cases, the consumer surplus, emission benefit and LRET payment reduces considerably. While the lower 'short run marginal cost' of wind power gives cheaper electricity to consumers, its availability makes a significant difference in consumer surplus. As the percentage of renewable generation is very less (7%) in Queensland, the proportion of emission and LRET benefit is high with the availability/unavailability of full wind capacity. The existing producers will get more benefit if there is no wind, whereas full wind generation gives revenue for wind generators though other generators will get a lower price due to likely cheaper power dispatch from wind turbines. Merchandizing surplus changes slightly due to the network utilization by wind generators, but proportionately this is negligible in long Queensland network.

The percentage changes in surpluses of producers [0.7, 0.2] and merchandisers [0.98, 0.8] are not significant compared to consumers [−7.0, 5.0], emission [−8, 29] and LRET benefit [−30, 80]. The net market benefit [−7.0, 6.0] has also been changed noticeably. Net market benefit is the accumulation of all benefits mentioned above. The scenario of 'no wind' to 'full wind' changes net market benefit from −7.0% to 6.0%. As the total market share of wind capacity in Copper String and Kennedy Wind Farm is around 11% in the Queensland electricity market, the availability and unavailability of wind capacity can largely influence the market benefits.

7. Conclusions

Although the regulatory framework for transmission investment in a market environment has been an active area of research, there has been little structured effort to date to understand the alternative paradigms for encouraging large scale renewable integration to an existing grid. An analytical framework to discuss some of the fundamental challenges associated with large scale integration of renewable generation in an electricity grid is presented in this paper. There are alternative regulatory paradigms which have their pros and cons that we have discussed first in the context of different regulatory practices around the globe. We have then used a multi-year transmission investment model to assess performance of transmission investment under alternative regulatory paradigms. Four case studies are presented to enhance remote renewable generation. The net market benefit framework is presented accumulating the producer, consumer, merchandiser and environmental surpluses. The proposed framework captures the long term benefit to obtain maximum social surplus. Accordingly, the cost allocation is

Table A1
Existing Queensland power plants with fuel-type, capacity, heat-rate and emission factor.

Name	Fuel	Capacity (MW)	Heat-rate (GJ/MW h)	Emission factor (t, CO_2/MW h)
Callide B	Coal	700	9.97	0.95
Callide C	Coal	840	9.47	0.92
Collinsville	Coal	187	13.00	1.19
Gladstone	Coal	1680	10.23	0.96
Kogan Creek	Coal	744	9.60	0.92
Millmerran	Coal	852	9.60	0.90
Stanwell	Coal	1400	9.89	0.91
SwanbankB	Coal	500	11.80	1.09
Tarong	Coal	1400	9.94	0.94
Tarong North	Coal	443	9.18	0.86
Barcaldine	CCGT	36	9.00	0.51
Condamine	CCGT	135	7.50	0.40
Darling Downs	CCGT	630	7.83	0.42
SwanbankE	CCGT	370	7.66	0.43
Townsville	CCGT	242	7.83	0.44
Braemer	OCGT	504	12.00	0.68
Braemer 2	OCGT	504	12.00	0.68
Oakey	OCGT	282	11.04	0.63
Roma	OCGT	68	12.00	0.68
Mackay	Oil	30	12.86	0.96
MT Stuart	Oil	415	12.00	0.90
Yarwun	Cogen	160	10.59	0.60
Barron George	Hydro	60	–	0
Kareeya	Hydro	94	–	0
Wivenhoe	Hydro	500	–	0
Windy Hill	Wind	12	–	0
Total (MW) 12788			avg. 10.22	avg. 0.65

Table A3
Indicative connection costs for new generation entry in the Queensland network.

NEM zone	Generation type	Transmission cost (m$/MW)
NQ	OCGT, CCGT	1.03
CQ	OCGT, CCGT	1.43
	Geothermal	1.56
SEQ	OCGT, CCGT	0.23
SWQ	OCGT, CCGT	0.63
	Geothermal	1.20

Table A2
Load profile and emission cost mark-up of Queensland electricity market.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Summer peak demand (MW)	8471	9,837	10,241	10,748	11,460	12,054	12,633	13,116	13,499	13,836	14,173
Emission cost (\$/ton CO_2)–ACIL	–	23.39	24.19	26.14	28.09	30.04	31.99	33.82	35.43	37.03	38.75
Emission cost (\$/ton CO_2)–AUgovt.	–	–	23	24.15	25.40	Market-driven					

Table A4
Load growth in different zones of the Queensland network.

Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Bulli	Moreton	Gold Coast
2.7	2.7	5.5	3.6	2.2	2.4	19	19	3.5	2.7

proposed to be distributed reasonably to enhance the renewable energy target and to control the rise in electricity price.

The regulatory challenges are highlighted as we compare the net market benefit outcomes across different paradigms. It is evident from the study that the proportion of market benefit shifts from one individual market participant to the other based on the composition of new generation portfolio and there are significant trade-offs among different components of benefits. For example, producer surplus is significantly reduced due to the commissioning of a 500 MW OCGT near the load centre (at Bulli). On the contrary, the consumer surplus increases considerably. The network constraints also affect the generation dispatch. Power penetration in South-West Queensland from the Cooper Basin project is more suitable to dispatch than the North Queensland region due to the huge (63%) consumption in the South-East Queensland region. Integration of these renewable projects helps to meet the renewable energy targets and lessens the LRET penalty.

The results obtained from the simulation identify the beneficiaries of low cost renewable power penetration to the grid. It is evident from the discussion that the employment of some projects (i.e., Cooper Basin in this case) can lessen the producer benefit, resulting in less market power and merchandizing surplus by alleviating congestion, at the same time it can provide a higher consumer benefit. Early identification and pro-active approach for this type of projects can largely enhance the benefit to the society as a whole. Most importantly this analysis can be a basis of justification for transmission investment and cost allocation. Logically, as the pro-active transmission augmentation brings a risk of stranding assets, consumers can bear that cost as the beneficiary of the network expansion. Since the success of major policy initiatives such as LRET and carbon tax hinges on successfully tapping into large clusters of renewables in Australia, these findings are extremely important for policy makers to fully appreciate the complexities involved in determining the appropriate policy settings. It is evident that the existing RIT-T framework does not provide adequate incentive to get some of the efficient transmission investments off the ground, which will ultimately lead to significant increase in LRET payments, and potentially shutting off significant green energy opportunities for ever.

This study can provide input to potential investors on the location of promising generation and transmission facilities. This information could be useful to regulators, system planners and market participants about the location, capacity and timing of generation and transmission augmentations.

An extension of this study is expected to incorporate a comparative assessment of HVAC, multi-terminal HVDC and hybrid transmission technologies. Some standard models of emission trading scheme will also be implemented in further studies.

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Table A5
Generation commitment in the Queensland network for the time horizon 2011–2020.

Year	Project	Zone	Capacity (MW)	Fuel type
2011	Victoria Mill	Ross	19	Black coal/bagasse
2011	Blackwater	CQ	30	Coal seam methane
2012	Kogan Creek (Solar Boost)	Bulli	44	Solar thermal
2012	High Road	NQ	35	Wind
2013	Forsayth	NQ	70	Wind
2013	Breamer3	Bulli	500	OCGT
2014	Darling Downs2	Bulli	500	OCGT
2014	Solar Dawn	SWQ	250	Solar thermal
2014	Westlink Power Project	SWQ	334	OCGT
2015	Burdekin Falls Dam	North	37	Hydro
2016	Westlink Power Project	SWQ	334	OCGT
2017	Wandoan Power Project	SWQ	504	IGCC
2018	Westlink Power Project	SWQ	334	OCGT
2019	Spring Gully	SWQ	1000	CCGT
2020	Bowen	North	200	Wind
2020	Coopers Gap	SWQ	350	Wind
2020	Crediton	North	90	Wind
2020	Crows Nest	Bulli	200	Wind
2020	Windy Hill II	Far North	30	Wind

Appendix

Existing power plants, fuel-type, capacity, heat-rate and emission factor of the Queensland network are shown in Table A1 [36]. Load profile and emission cost for 2010 to 2020 planning horizon are presented in Table A2 [31,36,44]. Emission cost data are obtained from the ACIL Tasman report and the 'Clean Energy Bill, 2011' [31,36,44].

Table A3 shows the indicative costs for new generation connection to the Queensland electricity network [45]. The cost of wind power generation is taken from the open-source information and consultant reports [46–48]. In this study, cost per unit of generated capacity, using capacity factor of South Australian wind farms are considered [47].

Zone-wide forecasted load is considered on the transmission network considering 50% PoE peak demand with average weather and diversity conditions and medium economic growth, as presented in Table A4 [35]. Further, Table A5 shows the generation commitments of the Queensland network for the year 2011 to 2020 [31].

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